UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

MAR 19 1997

Ref: 8P2-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Ms. Angela R. Ely
Administrative Operations Manager
Petroglyph Operating Company, Inc.
6209 North Highway 61
Hutchinson, Kansas 67502

RE: **UIC Minor Permit Modification**
**Conversion of Additional Well to**
Antelope Creek Waterflood
EPA Area Permit UT2736-00000
Duchesne County, Utah

Dear Ms. Ely:

Your letter of January 24, 1997, requesting that the following production well be converted to Class II enhanced oil recovery well and added to the Antelope Creek Waterflood, as authorized under EPA Area Permit #UT2736-00000, is hereby granted.

| NAME | LOCATION | EPA WELL PERMIT NO. |
|---|---|---|
| Ute Tribal #04-02 | NW NE Section 4<br>Lot #2<br>T 5 S - R 3 W | #UT2736-04356 |

This additional well is within the boundary of the existing area permit for the Antelope Creek Waterflood (UT2736-00000), and this addition is made by minor permit modification according to the terms and conditions of that permit. Unless specifically mentioned in this Minor Permit Modification, all terms and conditions of the original permit will apply to the construction, operation, monitoring, and plugging and abandonment of this additional injection well. The proposed well location, well schematic, conversion procedures, and revised plugging and abandonment plan and schematic, submitted by your office, have been reviewed and approved as follows:

(1) The **conversion** of this production well has been reviewed and found satisfactory as submitted, therefore, no corrective action is required.

(2) **Maximum injection pressure (Pmax)** - the permittee submitted a list of seven (7) individual zones, within the Ute Tribal #04-02, which were individually fraced and established an average fracture gradient (FG) of

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Scan under
UT 20736 - 00000
66 Modification - minor
mod approved 3/19/1997
Well need to link with
UT 20736 - 04356 in
new database also
under @1 add well to
Area Permit.

**CERTIFIED MAIL**
**RETURN RECEIPT REQUESTED**

Ms. Angela R. Ely
Administrative Operations Manager
Petroglyph Operating Company, Inc.
6209 North Highway 61
Hutchinson, Kansas 67502

RE: **UIC Minor Per**
**Conversion of**
Antelope Creel
EPA Area Perm
Duchesne Count

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0.87 psi/ft. which was derived from instantaneous shut-in pressures from each zone. This FG is acceptable to the Environmental Protection Agency (EPA), and a theoretical maximum allowable surface injection pressure (Pmax), for this well, may be calculated as shown below:

Pmax = [Fg - 0.433 (Sg)] d

Where: Pmax = Maximum surface injection pressure at wellhead

d = 5360' shallowest perforations

Sg = Specific gravity of injected water

Pmax = [0.87 - .433 (1.00)] 5360

**Pmax = 2344 psig**

Until such time as the permittee demonstrates that a fracture gradient other than 0.87 psi/ft applies to the disposal zones of this newly converted well, the maximum allowable wellhead injection pressure **(Pmax) for this well will be 2344 psig.**

(3) The **plugging and abandonment plan and schematic**, submitted by your office, has been reviewed, revised and approved.

**Prior to commencing injection into this well**, permittee must fulfill permit condition Part II, C. 2. and have received **written authorization** to inject **by the Environmental Protection Agency.** In summary, these requirements for your newly permitted injection well are:

(1) All conversion is complete and the permittee has submitted a completed **Well Rework Record (EPA Form 7520-12)**.

(2) The **pore pressure has been determined.**

(3) The well has successfully completed and passed an **mechanical integrity test (MIT)**, guidance and EPA form enclosed.

**All other provisions and conditions of the permit remain as originally issued.**

If you have any questions, please contact Mr. Chuck Williams at (303) 312-6625.

Also, please direct the above requirements to Mr. Williams at the above letterhead address, citing **MAIL CODE 8P2-W-GW.** Thank you for your continued cooperation.

Sincerely,

Kerrigan Clough

Kerrigan G. Clough
Assistant Regional Administrator
Office of Pollution Prevention,
State and Tribal Assistance

Enclosure: MIT Guidance and EPA Form

cc: Mr. Ferron Secakuku
Energy & Mineral Resource Dep't.
Ute Indian Tribe

Ms. Ruby Atwine, Chairperson
Uintah & Ouray Business Committee
Northern Ute Tribe

Mr. Jonas Grant, Director
Division of Natural Resources
Northern Ute Tribe

Mr. Norman Cambridge
BIA - Uintah & Ouray Agency

Mr. Gil Hunt
State of Utah Natural Resources
Division of Oil, Gas, and Mining

Mr. Jerry Kenczka
BLM - Vernal District Office

FCD: February 25, 1997, Chuck W. F:\DATA\WP\PETROGLF\MNRMD-04.02

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET · SUITE 500
DENVER, COLORADO 80202-2466

JUL - 6 1995

Ref: 8WM-DW

MEMORANDUM

SUBJECT: **Final Guidance for Conducting a Pressure Test to Determine if a Well Has Leaks in the Tubing, Casing or Packer**

FROM: Tom Pike, Chief UIC Direct Implementation

TO: UIC Direct Implementation Permit Writers

Introduction

The Underground Injection Control (UIC) regulations require that an injection well have mechanical integrity at all times (40 CFR 144.28 (f)(2) and 40 CFR 144.51 (q)(1)). A well has mechanical integrity (40 CFR 146.8) if:

(1) There is no significant leak in the tubing, casing or packer; and

(2) There is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection wellbore.

Definition: Mechanical Integrity Pressure Test for Part I. A pressure test used to determine the integrity of all the downhole components of an injection well, usually tubing, casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer. Pressure tests must be run at least once every five years. **If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the attached form or an equilivant form containing the necessary information. A pressure recording chart documentating the actual annulus test pressures must be attached to the form.**

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or packer). The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region VIII Primacy programs; and 4) to provide a procedure which can be easily administered and is applicable to all class I and II wells. Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region VIII's procedure for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

## Pressure Test Description

### Test Frequency

The mechanical integrity of an injection well must be maintained at all times. Mechanical integrity pressure tests are required at least every five (5) years. **If for any reason the tubing/packer is pulled, however, the injection well is required to pass another mechanical integrity test prior to recommencing injection regardless of when the last test was conducted. The Regional UIC program must be notified of the workover and the proposed date of the pressure test. The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate.** Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells).

Region VIII's criteria for well testing frequency is as follows:

1. Class I hazardous waste injection wells; initially [40 CFR 146.68(d)(1)] and annually thereafter;

2. Class I non-hazardous waste injection wells; initially and every two (2) years thereafter, except for old permits (such as the disposal wells at carbon dioxide extraction plants which require a test at least every five years);

3. Class II wells with tubing, casing and packer; initially and at least every five (5) years thereafter;

4. Class II wells with tubing cemented in the hole; initially and every one (1) or two (2) years thereafter depending on well specific conditions (See Region VIII UIC Section Guidance #36);

5. Class II wells which have been temporarily abandoned (TAd) must be pressure tested after being shut-in for two years; and

6. Class III uranium extraction wells; initially.

## Test Pressure

**To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.**

## Test Criteria

1. The duration of the pressure test is 30 minutes.

2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.

3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integity and should be shut-in until it is repaired or plugged.

4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed

Recordkeeping and Reporting

The test results must be recorded on the attached form. The annulus pressure should be recorded at five (5) minute intervals. **Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on the attached form or an equilivant form . A pressure recording chart documentating the actual annulus test pressures must be attached to the submittal.** The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded on the form. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

**Procedures for Pressure Test**

1. Scheduling the test should be done at least two (2) weeks in advance.

2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance #35 should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.

3. All Class I wells and Class II SWD wells should be shut-in prior to the test. A 12 to 24-hour shut-in is preferable to assure that the temperature of the fluid in the wellbore is stable.

4. Class II enhanced recovery wells may be operating during the test, but it is recommended that the well be shut-in if possible.

5. The operator should fill the casing/tubing annulus with inhibited fluid at least 24 hours in advance, if possible. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus can not maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to

the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

Following steps are at the well:

6. Read tubing pressure and record on the form. If the well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.

7. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures (Region VIII UIC Section Guidance #35) should be followed.

8. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.

9. Hook-up well to pressure source and apply pressure until test value is reached.

10. Immediately disconnect pressure source and start test time. (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted.) The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.

11. Record tubing and annulus pressure values every five (5) minutes.

12. At the end of the test, record the final tubing pressure.

13. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.

14. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours per Headquarters guidance #76. A follow-up

letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.

15. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.

16. Return to office and prepare follow-up.

Attachment

Is your RETURN ADDRESS completed on the reverse side?

**SENDER:** CEW 03/20/97 3005C MAR 21 1997

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to: UT2736-00000

Ms. Angela R. Ely
Administrative Operations Manager
Petroglyph Operating Company, Inc.
6209 North Highway 61
Hutchinson, Kansas 67502

4a. Article Number
P 078 121 144

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
3-24-97 2R5

5. Received By: *(Print Name)*
APRIL MENZIES

6. Signature: *(Addressee or Agent)*
X April Menzies

8. Addressee's Address *(Only if requested and fee is paid)*

cjo

PS Form **3811**, December 1994

Domestic Return Receipt

Thank you for using Return Receipt Service.

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P 078 121 144

**Receipt for Certified Mail**

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse) CEW 3005C

UNITED STATES POSTAL SERVICE

| | |
|---|---|
| Sent to: Ms. Angela R. Ely, Administrative Operations Mgr | |
| Street and No.: Petroglyph Operating Company, | |
| P.O., State and ZIP Code: 6209 North Highway 61, Hutchinson, Kansas 67502 | |
| Postage | $ |
| Certified Fee | |
| Special Delivery Fee | |
| Restricted Delivery Fee | |
| Return Receipt Showing to Whom & Date Delivered | |
| Return Receipt Showing to Whom, Date, and Addressee's Address | |
| TOTAL Postage & Fees | $ |
| Postmark or Date: MAR 20 1997 | |

MAR 20 1997
MAR 20 1997

UIC Minor Permit Modification
Conversion of Add. Well to
Antelope Creek Waterflood
EPA Area Permit UT2736-00000
Duchesne County, Utah

PS Form **3800**, June 1991

CONCURRENCE COPY

MAR 20 1997

Ref: 8P2-W-GW

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Done 3:08 3/19/97 To J. Grant

DEA 3/19/97

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Tabler 3-19-97

CEW 8P2-W-GW 2/26/97

8P2-W-GW 2/27/97

8P-ENF 3/19/97 notify tribe before permit is final.

DEA 3/17/97

CJO

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| | | | |
|---|---|---|---|
| Where: | Pmax | = | Maximum surface injection pressure at wellhead |
| | d | = | 5360' shallowest perforations |
| | Sg | = | Specific gravity of injected water |
| | Pmax | = | [0.87 - .433 (1.00)] 5360 |
| | **Pmax** | = | **2344 psig** |

Until such time as the permittee demonstrates that a fracture gradient other than 0.87 psi/ft applies to the disposal zones of this newly converted well, the maximum allowable wellhead injection pressure **(Pmax) for this well will be 2344 psig.**

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Kerrigan G. Clough
Assistant Regional Administrator
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State of Utah Natural Resources
Division of Oil, Gas, and Mining

Mr. Jerry Kenczka
BLM - Vernal District Office

FCD: February 25, 1997, Chuck W. F:\DATA\WP\PETROGLF\MNRMD-04.02